BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION)
OF IDAHO POWER COMPANY FOR)
AUTHORITY TO INCREASE ITS RATES)
AND CHARGES FOR ELECTRIC SERVICE) CASE NO. IPC-E-03-13
TO ELECTRIC CUSTOMERS IN THE STATE)
OF IDAHO)
)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JOHN R. GALE

Q. Please state your name and business address.

A. My name is John R. Gale and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company (Idaho Power or the Company) as the Vice President of Regulatory Affairs.

Q. Please describe your work experience.

A. In October 1983, I accepted a position as Rate Analyst with Idaho Power Company. In March 1990, I was assigned to the Company’s Meridian District Office for one year where I held the position of Meridian Manager. In March 1991, I was promoted to Manager of Rates. In July 1997, I was named General Manager of Pricing and Regulatory Services. In March of 2001, I was promoted to Vice President of Regulatory Affairs. As Vice President of Regulatory Affairs, I am responsible for the overall coordination and direction of the Pricing & Regulatory Department, including development of jurisdictional revenue requirements and class cost-of-service studies, preparation of rate design analyses, and administration of tariffs and customer contracts. In my current position, I am responsible for policy matters related to the economic regulation of Idaho Power Company.

Q. What role did you play in the preparation of the general rate case?

A. My role in the preparation of the general rate case was to oversee, manage, and coordinate the filing and to make the policy decisions related to regulatory matters.

Q. What was your interaction with the other Company witnesses?

A. I discussed the content and preparation of the witnesses' testimony and exhibits. I was assisted in this effort by Ms. Maggie Brilz and Mr. Greg Said, along with the Company's regulatory attorneys directed by Mr. Barton Kline.

Q. Please provide an overview of the Company's general rate case filing.

A. The Company leads with Mr. LaMont Keen, our President and COO. Mr. Keen speaks to the Company's financial condition and its management performance in recent years. Mr. Keen is our primary policy witness. Our next witness is Mr. William Avera, who has been retained by the Company as our return on equity (ROE) expert. Mr. Avera also performed this function for Idaho Power in our last general rate case. Mr. Avera’s recommended ROE range becomes an input to Mr. Dennis Gribble’s considerations. Mr. Gribble selects an ROE point estimate and includes that with the test year capital structure to derive the proposed overall rate of return.

Ms. Lori Smith then testifies to the financial inputs, both actual and estimated, that become our initial starting point for the system data for the 2003 test year. Ms. Smith includes system adjustments for deductions to certain expenses not allowed in rates, annualizing adjustments to expenses and rate base, known and measurable adjustments to expenses and rate base, and other adjustments to revenues, expenses and rate base related primarily to past Idaho Public Utilities Commission (IPUC or the Commission) orders. Mr. Obenchain takes Ms. Smith’s data, Mr. Gribble’s return recommendation, Mr. Said’s normalized net power supply expenses, along with other selected inputs and prepares the jurisdictional separation study (JSS). The JSS, as its name states, separates system values for rate base, revenues, and expenses for each state and federal jurisdiction by an assignment and allocation process. One result of the JSS is the Idaho retail jurisdictional revenue requirement.

As stated before, Mr. Said provides the normalized net power supply expenses for the test year. Mr. Said also addresses the requisite changes needed to the Company's Power Cost Adjustment as a result of changing the normalized net power supply expenses in Idaho Power's Base Rates.

Ms. Brilz takes the Idaho retail jurisdictional output from Mr. Obenchain and further separates costs by customer class and special contract through a class cost of service (CCOS) study. Additionally, Ms. Brilz proposes price changes to the customer classes that are consistent with the Company's ratemaking objectives and recover the Company's Idaho revenue requirement. Ms. Theresa Drake addresses additional changes to Idaho Power's tariffs and non-recurring charges.

Ms. Susan Fullen provides information regarding a variety of Idaho Power's customer-related activities, including the results of recent customer satisfaction surveys. Finally, I finish the direct case addressing regulatory policy issues.

Q. What was Idaho Power Company’s executive management involvement with the preparation of the general rate case?

A. Idaho Power’s Office of the Chief Operating Officer, consisting of the Company’s President, Senior Vice President of Delivery, Vice President of Power Supply, Vice President of Corporate Services, and myself along with the Chief Financial Officer, served as the oversight group.

Q. What are the policy issues related to the preparation of the test year financial information?

A. The policy decisions related to the preparation of the general rate case include the selection of the test year, the decision to use a split year, the treatment of annualizing adjustments, and the treatment of known and measurable adjustments.

Q. What is the Company’s test year?

A. The Company’s test year is the 12 months ending December 31, 2003.

Q. Why did you choose 2003 as the test year?

A. Using a test year of 2003 provides the most recent information available as to the Company’s expenses and investments. The year captures increased levels of capital and O&M spending that are needed to fund our utility infrastructure. The year also provides a clear break with our past affiliate transactions with IDACORP Energy (IE).

Q. Why did the Company choose to file with a split test year that used both actual and estimated data?

A. The split test year using six months actual and six months estimated data offers rate recovery closer to the time that costs are incurred, allows the timing of general rate changes to be coordinated with and potentially mitigated by PCA changes, and provides the Commission an opportunity to see actual information for the whole year before issuing its final order.

Q. What was the basis for making annualizing adjustments to rate base for 2003?

A. The annualizing adjustments to rate base for 2003 are related to electric plant in service items closing to book during the last half of 2003. These items and their related impacts (such as depreciation and property tax) were treated as if they were in place for a full twelve months.

Q. Please describe the annualizing adjustment to the 2003 operating expense related to payroll.

A. The annualizing adjustment to the 2003 operating expense related to payroll, changes the payroll expense to an amount reflective of what it would have been had the year-end payroll expense been in existence for the full year in 2003.

Q. What was the Company's basis for including known and measurable additions to its rate base?

A. The Company included only assets of a material size that were planned to close to the books before June 1, 2004. These assets are major projects related to transmission and transmission substation. The Company chose June 1, 2004 as the cutoff for known and measurable plant adjustments because that is the date that the proposed rates are expected to become effective if the Commission uses the full time to issue its order.

Q. Please describe the rationale for including a known and measurable adjustment to operating expense for employee incentives.

A. Since the last general rate case, Idaho

Power has made a material change in the manner in which it compensates its employees. Starting in 1995, the Company modified its existing “cash” compensation to include an element of “pay at risk”. The new plan continues to provide a fixed base salary, but now includes the potential for an incentive. Since the incentive can vary from year to year according to Company and employee performance, using the actual incentive amount as part of the test year compensation can be misleading. Because the range of potential outcomes is large, a normalized number is more reflective of ongoing compensation than an actual amount.

Q. Why do you use the term “pay at risk”?

A. Before the incentive was introduced, the Company targeted its base pay upon the 60th percentile of the relevant labor market rate for the specific job category. After the incentive was added to the compensation package, the benchmark for the base pay was reduced to the 50th percentile. The difference between the two percentile levels became the pay at risk.

Q. What is the difference between the two percentile levels worth in percentage terms?

A. Based upon our 2002 wage information, the difference is approximately 7 percent. This figure can vary slightly from one year to the next based on changes in the market place, but in general the market changes are not large enough to cause significant change.

Q. Why did you make a known and measurable adjustment related to salary structure?

A. The known and measurable expense related to salary structure adjusts payroll expense to account for an employee general wage adjustment (GWA) at year-end 2003. The adjustment for the GWA was 3 percent.

Q. What was the basis for the Company known and measurable for pension costs?

A. There are three options which reflect the cost of providing pension benefits to our employees: (1) Pay As You Go, (2) Service Cost, and (3) Pension Expense. The Pay As You Go reflects the actual benefits paid to employees receiving pension benefits during the relevant time period. The Service Cost benefit amount reflects the cost to provide a new year of benefits to employees. The Pension Expense method reflects the cost to provide the benefits including the volatility of market movements that impact the pension plan assets and the impact of interest rate movements. Using the Service Cost method for ratemaking purposes removes the market volatility and interest rate volatility, while quantifying the annual cost of providing a new year of benefits to employees. The test year information was adjusted to reflect service costs for 2003, which the Company believes to be more representative of our pension costs going forward.

Q. How have the Operating Revenues of the Company been adjusted?

A. The Operating Revenues are primarily adjusted through the normalizing adjustments to the Company’s net power supply expenses as a result of multiple water conditions discussed by Mr. Said. Other known changes to tariffs or contracts were also included either in the test year revenues or adjustments to the test year. Sales revenues for the test year 2003 were based on weather normalized retail sales for the first six months and estimated normalized sales for the later six months.

Q. What are the policy issues related to the rate spread and rate design proposed by the Company?

A. The policy issues related to rate spread and rate design are that rates should be primarily cost-based, adjustments to the rate spread, an emphasis on fixed cost recovery, and the introduction of time-of-use pricing (both seasonal and diurnal).

Q. What is the Company’s philosophy on setting rates?

A. In the last several general rate cases, the Company’s primary approach to ratemaking has been to reflect costs as accurately as possible in setting its tariff rates. Accordingly, the Company’s ratemaking proposals usually advocate movement toward cost-of-service results which assign costs to those customers that cause the Company to incur the costs. The Company realizes that there are other ratemaking objectives, such as ability to pay, that the Commission may consider in making its determination. However, the Company believes that the best starting point for Commission deliberations is an economic one. Nevertheless, some ratemaking situations cause such abrupt change, the Company has proposed some limits to the movement toward cost-of-service.

Q. How did you approach rate spread among the customer classes and special contracts?

A. Rate spread is a term that refers to the division of the jurisdictional revenue requirement into individual revenue requirements for each customer class and special contract. Each special contract is essentially a rate class of one customer. The CCOS results are one means of performing rate spread. Please refer to Exhibit No. 61, a four-page exhibit that steps through the revenue requirement allocation process from the CCOS results to the Company's ultimate proposal for each customer class and special contract. Page 1 of Exhibit No. 61 is the proformed normalized test year sales and revenues. Page 2 indicates the adjustments in terms of percentages and dollars that would be made to each customer class to obtain the results indicated by the CCOS. A pure CCOS rate spread would mean a 67.1 percent increase to the irrigation customer class. Page 3 constrains the changes to the revenue allocations in order to mitigate the magnitude of the rate increase to the irrigation customer class. A 25 percent limit is placed on the increase to irrigation, while the small unmetered classes are held at zero instead of the decreases indicated by the CCOS. Page 4 spreads the revenue shortfall created by the mitigation back to the other customer classes, so that the total Idaho jurisdictional target revenue can be obtained.

Q. Has the Company’s cost-based approach influenced other rate design proposals?

A. Yes, the cost-based approach has led to rate design proposals that better align fixed costs with fixed prices and variable costs with variable prices. Ideally an energy rate that corresponds to our energy costs would help address a number of rate-related issues, including net metering and customer conservation decisions. The emphasis on moving fixed and variable prices to be more reflective of fixed and variable costs led to the Company’s proposals to increase the monthly service charge for residential and small general service customers. Since these customers are not demand metered, the service charge is the only fixed rate component available to adjust and thus becomes more important as a tool for fixed cost recovery. The increases to the service charges are a moderate step toward better alignment of costs and prices. However, as described by Ms. Brilz, there is still a long way to go.

Q. Did the Company’s cost-based approach influence any other ratemaking proposals?

A. Yes, the cost-based approach also influenced our decision to propose seasonal and time-of-use rates for certain customer groups. Both types of time-based rates allow for the incorporation of time-based cost differences into the Company’s pricing.

Q. Should the Company’s seasonal rate proposals be adopted, is there a related issue concerning the Company’s Power Cost Adjustment (PCA)?

A. Yes, because the summer season is proposed to begin on June 1 and the current PCA is scheduled to change on May 16, the Company believes it would be best to consolidate the two rate change dates into one. As Mr. Said states in his testimony, we are proposing to move the start date for each year’s PCA to June 1. In addition, the change would give the Commission the benefit in the future of an extra two weeks to process the annual PCA application.

Q. How has depreciation expense been treated in the rate filing?

A. The depreciation expense in the Company’s general rate request includes the depreciation rates contained in the Company’s application filed with this Commission on May 6, 2003 in Case No. IPC-E-03-07. Since that time, a stipulation has been reached among the parties regarding that case and filed with the IPUC on October 9, 2003. (Should the IPUC approve that stipulation, the overall requested revenue requirement would adjust downward to incorporate the final action).

Q. Have the Company and Commission Staff attempted to settle other rate issues recently that may have an impact on the general rate case?

A. Yes. The Company, the Commission Staff, and the Industrial Customer of Idaho Power have reached verbal agreement regarding the final settlement of issues in Case No. IPC-E-01-16, a case pertaining to the relationship between IE and Idaho Power, including appropriate compensation to be paid by IE to Idaho Power for the use of Idaho Power’s transmission and capacity resources. If approved, the settlement of Case No. IPC-E-01-16 will bring past issues between Idaho Power and IE to closure.

Q. Are you generally familiar with the Company’s recent management efforts in the areas of stewardship of the system, customer service, demand-side management, and financing activity?

A. Yes. As described in detail by Ms. Fullen, the Company has implemented a new business model that better serves customers. That model includes changes that improved outage management and communication systems, improved customer service systems throughout the Company's service territory, demonstrated performance of our metering and billing systems, renewed focus on demand-side management programs, and improved customer satisfaction results.

On the financial side of the business, the Company has utilized available opportunities to refund various issues of both long-term debt and preferred stock on a cost-effective basis. This has resulted in significantly lower embedded costs. At the time of the Company's last Idaho general rate case, the Company's overall cost of debt capital was 8.024 percent. The Company's current cost of debt capital is 5.983 percent. Mr. Gribble speaks to the financing efforts in his testimony.

And despite all the stresses on the system both internal (heightened emphasis on reliability, increased demand for infrastructure investments, increasing relicensing costs, poor cash flow, and negative earnings implications) as well as external (major drought, out of step inflation in energy markets, market chaos, and the eventual exodus of credit worthy counterparties and investment dollars), in the end, Idaho Power has honored its obligation to serve our customers and keep the lights on at a reasonable price. Mr. Keen's testimony describes these activities and results in greater detail.

Q. Are there other instances of Company management decisions that have been helpful to its customers?

A. Yes. I would like to highlight two other areas in which the Company has made great strides. The first is our Green Power Program and the second is Idaho Power's development of a comprehensive risk management policy over the last two years.

Because of Idaho Power's hydroelectric resources, our customers get most of their electricity from a resource that's virtually emission-free. With the establishment of our Green Power Program, customers have yet another emission- free alternative -- wind power. The Green Power Program is a voluntary program that allows Idaho Power customers to add any dollar amount they choose to their power bills to purchase resources from the Stateline Wind

Project. The Company has sponsored multiple campaigns aimed at generating awareness and encouraging customers to enroll in the program. Enrollment in the two-year-old program has grown nearly 20 percent since the last campaign bringing the number of participating subscribers to almost 2000.

The second area of Company business that I would like to highlight is risk management. It became clear to the Company’s Risk Management Committee (RMC) during the 2000-2001 Energy Crisis that our risk management techniques for dealing with the market and the associated drought worked well in most cases but not in all. Learning from this experience, the Company acquired new energy, made investment to increase capacity and reliability throughout the system, adopted more conservative financial policies, and developed and implemented a state-of-the-art risk management policy. This collaborative risk management strategy protects against adverse movements in net power supply costs and manages the cost of energy supply with respect for the risk tolerance of stakeholders. Together, these strategies will lead to more stable rates.

Q. Do you believe it is in the public interest for the Commission to recognize these management efforts in setting Idaho Power rates?

A. Yes. Traditionally, this is done by the Commission adding basis points to the authorized rate of return.

Q. In its general rate application, is the Company requesting additional basis points in its authorized rate of return on equity to recognize good management performance?

A. No.

Q. How would the Company like to be recognized by the IPUC for its management performance?

A. The Company would like to be recognized through timely and positive consideration of our rate relief request.

Q. Is it your opinion that the granting of the rate relief proposed by the Company is in the public interest?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.